Non-intrusive ultrasonic corrosion-rate measurement in lieu of manual and intrusive methods

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ABSTRACT

Technologically advanced, fully-digital ultrasonic wall-thickness measurement systems coupled with Internet of Things (IoT) back-haul data communication schemes, including cellular, are enabling transportable, accurate and cost-effective corrosion-monitoring systems that can compete with older and more traditional methods. Comparisons show improved data accuracy of permanently-installed sensors in lieu of larger quantities of manually-taken spot data. This paper will include the design principles used in the creation of this next-generation platform.

Key words: Ultrasonic thickness measurement, UT, TML, CML, Corrosion, Erosion, Corrosion Rate, Non-intrusive, Wall thickness monitoring, IoT, M2M.

INTRODUCTION

For many refinery and petrochemical plants, much of the fixed equipment has greatly exceeded the economic design lives and the continued use has been validated by the use and trending of equipment thickness readings. Some refineries have up to 3 million Thickness Monitoring Locations (TMLs) or Corrosion Monitoring Locations (CMLs) that are used for this purpose. Many internal and industry codes require these types of readings on a periodic basis. As such, asset inspections are required by operators and are mandated in regulations and codes such as 29CFR–1910; American Petroleum Institute (API) [(1)] 570, American Society of Mechanical Engineers (ASME) [(2)] Sections V & XI, ASTM International (ASTM) [(3)] E797 and National Association of Corrosion Engineers (NACE) [(4)] IP 34101.

There are many methods for measuring wall thickness; a predominant method is the use of portable ultrasonic equipment. Ultrasound is non-intrusive as it is applied to the outside of the pipe or vessel, is accurate and relatively low cost for a single deployment in most situations. However, the ultrasonic transducer needs to be applied in direct contact with the external surface of the pipe requiring repetitive scaffolding, excavation, stripping of coatings or insulation, etc. Thus, the cost of access to the structure generally far exceeds the basic cost of inspection. Furthermore, a trained and certified inspector is required to operate the ultrasonic instrumentation, requiring personnel to sometimes be exposed to potentially hazardous environments. The accuracy and repeatability of ultrasonic measurements are operator-dependent and recent studies have shown that the probability-of-detection (POD) can be poor (O'Brien) [(5)]. Finally, the measurements are only performed periodically, taking a snap-shot of plant condition.

Many end-users are interested in investing in installed-sensor technology to overcome these concerns. The automation of thickness measurements compared with manual/periodic measurements of thickness and corrosion rate, as an on-line process, that can be used to optimize asset life and inspections.

Background

A recent survey of O&G plant operators found the following responses when asked about monitoring asset health:

- Desire new technology that can provide more current data on the condition of their assets.
- Do not want to wait for annual inspections or shutdowns to get this data.
- Want on-line monitoring versus periodic data collection.
- Want more and quicker data of higher quality.

Furthermore, in plant environments, some equipment cannot even be accessed during shutdowns. Data still must be obtained for these assets, which can be more critical to overall plant integrity. Every plant manager interviewed is interested in knowing the condition of his / her plant every day, regardless of service status or location of assets.

Most end users are interested in investing in new technology to overcome these concerns. In the process industries, such as in petrochemical or refineries, all critical process parameters are measured in real time. Information on flow, temperature, pressure, pH, equipment upsets or unusual conditions is monitored and reported on a continuing basis via Key Performance Indicators or KPI's. The Plant Manager then can feel that he / she is in control. Manually derived thickness data does not result in the same level of visibility to plant health.

From an asset-management perspective, corrosion-rate measurements are also of interest. Plant operators currently use technologies such as Electrical Resistance (ER) probes or corrosion coupons as a proxy for measuring the corrosion rate due to the process stream. The result is a feedback loop where process variables and corrosion inhibitors are adjusted to minimize the corrosion rate with a typical target being <10 mils (0.010"; 0.25 mm) per year (MPY)

While technologies such as ER probes and coupons are widely used, they have the following limitations:

- The technology relies on a coupon or probe being installed within the pipe, requiring the pipe's pressure boundary to be penetrated.
- The technology does not produce a direct measure of asset integrity, as the actual pipe wall is not being measured.
- Often, the element is a different material than the piping it represents.

- Installation and retrieval of the probes and coupons can be hazardous, and deployment of inspection locations is expensive.
- Installations are fixed and cannot be easily re-deployed to problem areas.

Thus, new solutions are desired for corrosion-rate monitoring as well.

A New Solution: Installed Ultrasonic Sensors

Installed ultrasonic sensors are emerging as a new technology to compete with manual UT inspections and existing or traditional corrosion-rate monitoring solutions. Installed ultrasonic sensors bring the potential for high data quality, non-invasive installation, ability to operate remotely without operator interaction and the reduction of personnel access costs over time.

Similar to UT thickness gauging, the solution is based on the ultrasonic principle as shown. (Figure 1) A transducer is used to convert electrical energy to high-frequency acoustic or ultrasonic energy and vice-versa and is semi-permanently attached to the surface of the object or asset under test. The transducer is electrically pulsed to generate a stress wave in the object and subsequently converts returning echoes to voltage. The resulting waveform (A-scan) is then recorded and measured by the ultrasonic instrumentation. The transit time between the initial pulse and return echoes (or between successive echoes) is used to calculate wall thickness. Features such as the distance to the back-wall or the distance to a pit or crack can be very accurately measured with this technique.

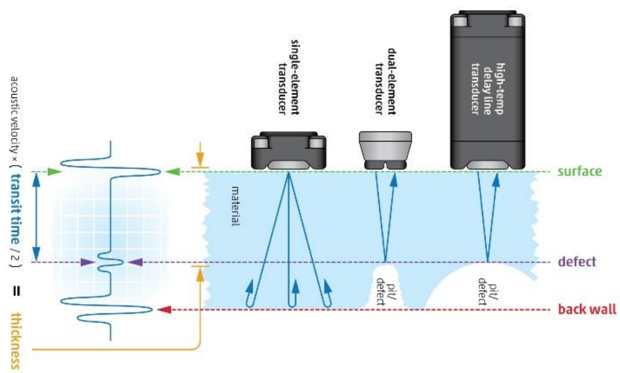


Figure 1: Ultrasonic Testing principle measures the round-trip transit time of the acoustic energy in the material under test. Wall thickness is calculated from the time measurement.

Operationally, the installed sensor solution is similar to manual thickness gauging; however, it is fundamentally different in that the transducers and instrumentation are deployed semi-permanently or permanently on the asset. This addresses several of the shortcomings of existing solutions.

Some of the major advantages are as follows:

1. Instrumentation and probes are deployed on the asset in a permanent or semi-permanent fashion and can be accessed remotely, thus the cost of access is reduced over time and operators are not deployed to the point of the inspection. Once the instrumentation is deployed, data can be accessed from a convenient access point for the manual data collection option or can be accessed remotely, via the Internet, for integrated systems.
2. Due to the fixed transducer position and instrumentation, operator-to-operator, probe-to-probe, and instrument-to-instrument variability is eliminated. This removes significant sources of error

and allows for improved measurement resolution, precision, and accuracy, which is particularly important for accurate corrosion-rate trending.

3. Data can be collected on a more frequent basis (>1X per day) for automated systems. This allows for more accurate corrosion-rate trending through statistical data analysis, such as linear least squares regression.
4. The system can be deployed with an integrated temperature measurement device so that changes in material acoustic velocity due to temperature variation can be automatically removed from the measurement, thus eliminating another significant source of measurement error.
5. The data is accessible. Wired and/or wireless installed sensor systems can make use of various forms of data backhaul including the plant wired or wireless intranet, industrial wireless networks such as 802.15.4, satellite or cellular networks for remote collection points, allowing practically real-time data/asset health availability.

System Concept

The concept is to develop a flexible and cost-effective system for deploying hundreds to thousands of installed ultrasonic sensors. The system is modular, scalable and is offered in both wired and wireless versions, using industry-standard communication protocols to allow integration with existing plant equipment and control systems or backhaul to a cloud-based database using cellular or wireless connectivity.

Figure 2: Installed sensor corrosion monitoring application for buried pipelines.

Figure 3: Schematic view including wired and cellular wireless transmitters, transducer types and tablet PC for either manual or fully-automated data collection.

System controller: The system controller is a tablet PC, industrial computer, or remote terminal unit (RTU) depending on whether the data collection will be manual, automated or integrated with a plant control system. The system controller communicates with the network of digital sensor interfaces or "DSIs" via Modbus over RS-485, which is standard industrial instrumentation protocol. The system controller then transmits the data for viewing, analysis and/or archiving. For wireless systems, the system controller is replaced with a cellular transmitter.

Digital Sensor Interface (DSI): The digital sensor interface is an ultrasonic data collection instrument that is connected with up to 16 transducers and serves the purpose of pulsing and receiving data from the transducers, digitizing the collected data, processing the digital ultrasonic data into thickness values and transmitting the data to the system controller. The DSIs are arranged on a multi-drop network such that a single cable drop can be used to connect up to 32 DSIs representing a maximum 512 individual transducers. For any given DSI, transducers may be arranged randomly, or in a linear or area array, giving users the versatility to monitor specialized infrastructure such as a pipe-elbow extrados.

Transducers: The ultrasonic transducers transmit and receive ultrasound and are available in several models and types based on the application to be solved. For example, dual-element transducers are particularly well suited for thin measurements (< 0.100" or 2.5 mm) and highly-pitted back-wall surfaces. The transducers can be dry coupled to the pipe using a proprietary elastomeric material (for standard temperatures), adhesively bonded, or clamped with metal foil for high-temperature models.

Table 1: Transducer Configuration

Type	Temperature	Application
Single-element Contact	Standard / Ambient	General purpose
Delay-line Contact	Medium to High	High precision, High temperature
Dual-element	Medium	General corrosion, pitted surfaces
Angle-beam or shear-wave	Standard to Medium	Crack detection

Transducers can be arranged in different configurations such as random, linear, or area arrays to suit the needs of the application.

Precision Thickness Measurement

Many different methods are used in modern thickness gauging products. The drawing below will be used in the following discussion to explain a method called Zero Crossing measurement.

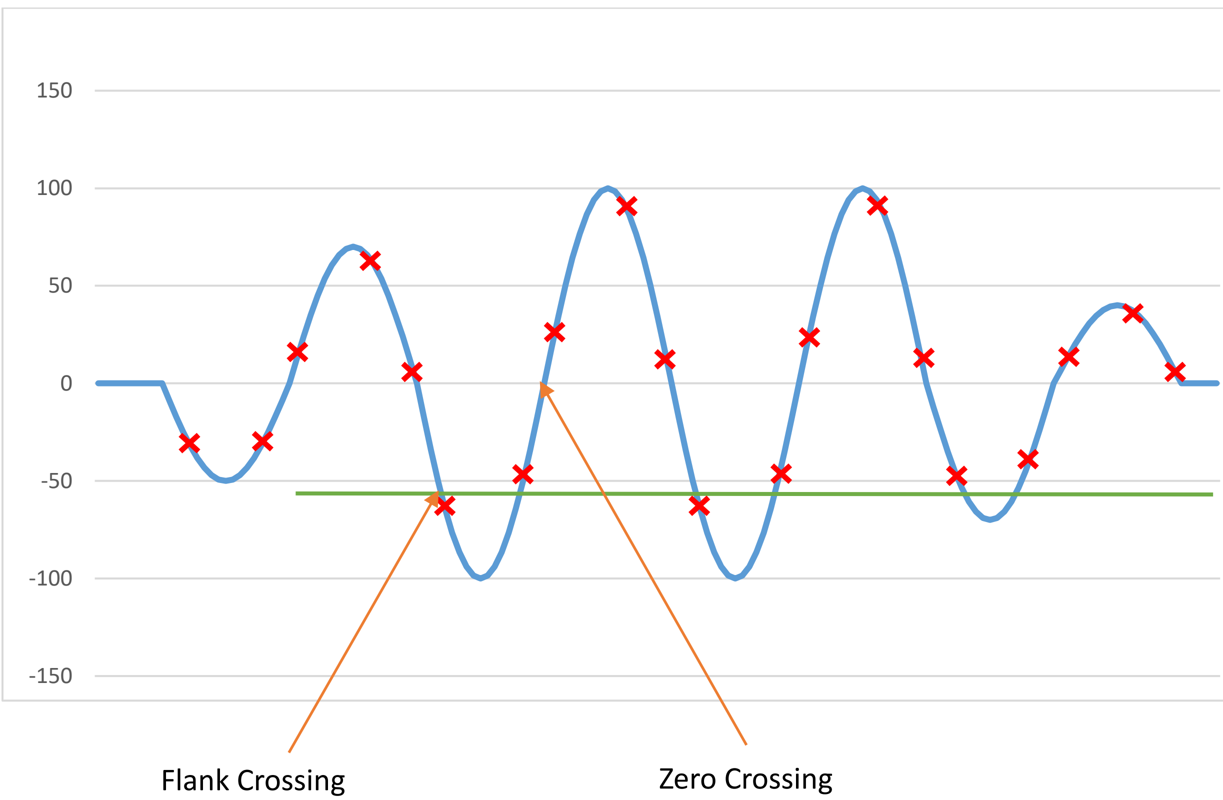


Figure 4 Wave Form Configuration

One of the first considerations is what point on the waveform should be used in the thickness calculations; finding a stable point on the waveform is key. When using a flank-detection method, as the amplitude of the return echo changes, the slope of the line changes and then the point in time where the echo crosses the gate threshold moves; having a negative effect on the stability and accuracy of thickness measurements. As the echo amplitude changes, and thus, the slope of the line changes, it tends to pivot around the zero crossing point. The time shift (horizontal movement) of the Zero-Crossing point is less affected by amplitude variations than any other point on the waveform, making it the ideal point on the waveform to calculate the thickness from.

Most modern UT systems digitize the waveform of the returning echoes and then use digital signal processing techniques to make the thickness measurement. The speed at which the return echo is sampled is a compromise between cost, power consumption and accuracy. The higher the speed at which the signal is sampled the more accurate it is. However, this comes at the price of higher cost and greater power consumption. Digital signal processing techniques can be used to increase the resolution of the thickness measurement without increasing the sampling speed, saving cost and power consumption. In simple terms, the signal processing can be thought of as interpolation between the sampled points. A very complex mathematical routine known as up-sampling is used to calculate additional points between the actual sample points. These up-sampled points are then searched to find the point just under and just above the zero line. A final, linear interpolation between these two points can then be performed to find the time of the zero crossing with a very high level of precision. This precise time is then used in the standard equations used to calculate thickness values:

$$\text{Thickness} = (\text{Measured Time x Material Velocity}) / 2$$

Equation 1: Ultrasonic Thickness Measurement

Dual-element transducers are commonly used when making thickness measurements on corroded pipes. Dual probes are better for finding pits and making measurements on test points with non-parallel (front and back) surfaces. However, dual probes introduce some additional variables into the thickness calculation equation due to the time that the sound spends traveling through the delay lines in the probe and in the test part due to the V-path. The following drawing shows this concept:

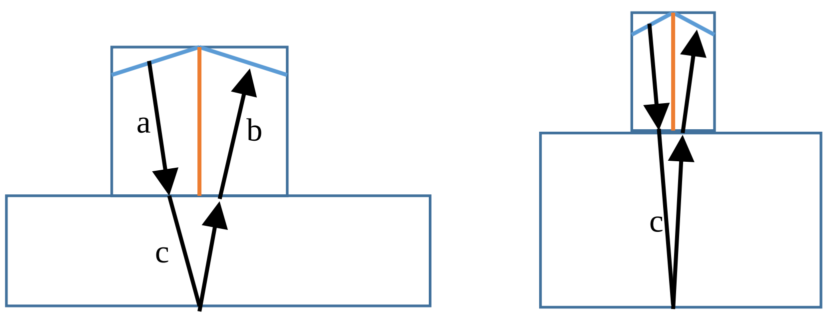


Figure 5: Dual element delay line concept

Letters ‘a’ and ‘b’ in the drawing represent the time spent in the delay line portions of the probes. This time is normally calibrated or backed-out of the thickness measurement at the time of calibration. When using installed sensors, since transducer wear is not a concern, a single initial calibration is sufficient. Line ‘c’ represents the time the sound spends in the part being inspected. As you can see, this line has a ‘V’ shape when using a dual probe. The actual thickness is the vertical distance between the top and bottom surfaces. As the thickness of the part changes, the amount of error due to the V-path changes. In a thinner part, V-path error will have a larger percentage error in the thickness measurement than in a thicker part. A common method to correct for this error is to make a larger number of precision measurements with each type of probe and build a table of correction values to be used in the thickness calculation. With a dual probe, the thickness equation becomes:

Thickness = [(Measured Time – ‘a’ – ‘b’ – V-path Correction value) * Velocity] / 2

Equation 2: Dual Element Ultrasonic Thickness Measurement

Temperature measurement device: To achieve the most accurate and precise readings using ultrasound, it is necessary to correct the ultrasonic velocity for changes that occurs due to changes in asset temperature. The system incorporates a RTD (Resistance Temperature Detector) that can be placed on the asset adjacent to the ultrasonic transducers.

Data reporting: The system incorporates a cloud-based solution for data management allowing for real-time access to thickness and corrosion-rate data from any connected device with an internet browser. This allows for accurate and near real-time data reporting from the sensor locations as well as the ability for reporting alert conditions via email or text. The solution can be hosted by any internet cloud provider or on a company’s internal computing resources. For portable data collection with a tablet PC solution, data and report files can also be emailed from the device.

Wired vs. Wireless Solutions

Developing a flexible solution for corrosion/erosion monitoring with both wired and wireless data backhaul options was achieved. The wired solution uses Modbus over RS-485, which allows sensors to be deployed in a multi-drop fashion that minimizes wiring complexity and cost.

One wireless version implements a mesh network solution using wireless HART (wiHART). Wireless HART is the most widely used plant solution, versus alternative solutions such as ISA100 and ZigBee. A non-proprietary solution is advantageous as devices can interoperate on the mesh network with other wireless devices such as temperature controllers, flow meters and others as offered by companies such as Emerson-Rosemount. wiHART is not always available or practical due to its costs and the complexity of IT integration thus a simpler option is made available with Cellular back-haul connectivity.

<u>Cellular Wireless</u>

Advances in technology have made it possible to embed cellular modems into industrial products and bring connectivity to places where it was previously expensive, difficult or impossible. This trend, and its underlying technologies, are part of an industrial trend commonly called IoT (Internet of Things) or M2M (Machine to Machine). Below is an example of a cellular modem that is currently being embedded in an installed sensor application.

Figure 6: Embedded Modem size comparison

Continuous changes in cellular communications bring many challenges to the designers and manufacturers of this equipment. The shift from 2G (2G is Second Generation Wireless, 3 G is Third) to 3G to 4G and LTE (Long-Term Evolution) technologies brings greater bandwidth and, thus, more functions available to consumers, but it forces manufacturers to keep pace with this technology. As an example, some telecom companies plan to decommission its 2G network by the end of 2017 with other major carriers planning a similar move within the next few years. Equipment with 2G radios installed will cease to function when these older networks go away. The selection of a cellular modem will allow easier upgrades of equipment than an instrument that was designed with the cellular functionality implemented directly on the circuit boards of the equipment.

While the drive for greater bandwidth is desirable for consumer products, such as cell phones and tablets, it is not always necessary for many industrial IoT applications. These applications transmit a relatively small amount of data at infrequent intervals. Today, we are paying for this excess speed and bandwidth in both cost and power consumption of the cellular modules. Cellular providers and the companies who manufacture the modules are aware of the gap and are planning to roll-out new products and services that will be optimized for IoT / M2M applications. These new technologies will bring both lower costs and lower power consumption to devices that need less bandwidth, but need cellular connectivity to bring results back to the user. Over the next several years, terms like CAT1 (Category 1 cable and other telecommunication terms like, CAT0, M1, and M0) will be used to describe the connectivity schemes and technologies used for M2M applications much like 2G, 3G, and 4G are used for cellular phones today.

While wireless solutions may be viewed as superior to wired solutions due to the lack of cabling costs, there are many factors to consider when choosing the optimum system for a given application.

<u>When Wired Solutions Are Optimum:</u>

- Buried installations
- Integration with plant control systems
- Lowest hardware cost per TML
- Manual, automated, and integrated data collection options
- Data-collection frequency >2X per day
- No battery replacement required
- Resistant to RF interference
- Applications: Buried pipelines, offshore / integrated erosion monitoring, manual data collection solutions.

<u>When Wireless Solutions Are Optimum:</u>

- Wiring cost is prohibitive or impractical
- Fully-automated and integrated data-collection solution
- Typically, <2X per day measurement frequency
- Transmitters / transducers need to be periodically repositioned
- Applications: Refinery, power, and process plant corrosion monitoring.

Ultimately, it is advantageous to have both wired and wireless options available to optimize the cost and performance of a corrosion-monitoring system for an application. Hybrid solutions can also be advantageous, for example using a wired system for a buried pipe application with wireless data backhaul at the system controller with cellular or satellite communications.

Accuracy, Precision, and Resolution

Ultrasound can make very accurate and precise measurements of object wall thickness. Typical corrosion thickness gauges usually have a display resolution of 0.001” (0.025mm) and precision gauges usually display resolution to 0.0001” (0.0025mm). While accuracy and precision can approach this gauge resolution in the lab or on calibration standards, the field accuracy and precision has been shown to be orders-of-magnitude worse, primarily due to operator and equipment variability.

There are many factors that affect the accuracy and precision of ultrasonic thickness measurements taken in the field, as shown below in Table 2.

Table 2

Factors Affecting Gauge Accuracy and Precision in the Field

Accuracy	Precision
Operator variability	*Operator variability*
Sound velocity and acoustic zero calibration	*Velocity and acoustic zero cal (msmt to msmt)*
Echo quality	Echo quality
Sound velocity uniformity	Electronic or ultrasonic noise
Surface roughness	*Transducer placement variability*
Transducer coupling variability	*Transducer coupling variability*
Temperature variation	Temperature Variation

** Parameters in italics are eliminated or reduced with installed sensors*

Many of the factors that contribute to variability in the accuracy and precision of UT readings can be removed with installed sensors, primarily due to the removal of operator-to-operator and transducer placement variability. Other factors can be controlled through optimization of the application, such as choosing transducers that are suitable for the thickness range to be measured and the expected surface condition based upon corrosion type. For example, using dual-element transducers when measuring highly-corroded or pitted surfaces is appropriate. An optimized wall-thickness monitoring system can achieve 0.0001” or 0.0025 mm resolution.

Temperature variation can also introduce significant errors in accuracy and precision, particularly for assets that operate at elevated temperatures or swing through wide temperature ranges especially when taken off-line. Thickness monitoring systems that have integrated temperature measurement devices, such as thermocouples, allow for the potential to compensate for temperature changes and remove the deleterious effects on accuracy and precision.

The Power of High-Frequency & High-Quality Data

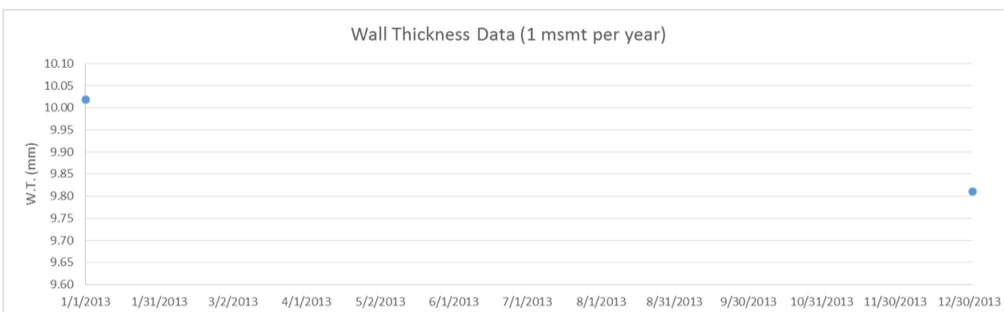
A major advantage of installed ultrasonic sensors is the ability to collect a larger quantity of high-quality thickness data than would otherwise be practical from manually-collected measurements. The large amount of data allows visibility to the dynamics of wall thickness reduction. Corrosion rates are often not constant and can vary between periods of virtually zero corrosion to episodic events causing corrosion rates of hundreds or thousands of MPY. The use of data of marginal quality that has been collected over long time periods can either overestimate or underestimate corrosion rate and does not allow insight into the actual corrosion history of an asset.

Figures 4 a-d shows a data set including eight distinct corrosion rates with noise having a standard deviation of 0.01mm (0.0004”). Progressing from Figure 4a to Figure 4d is the same data, displaying discrete measurements from the data set on intervals of 1X per year, 1X per month, 1X per week and 1X per day.

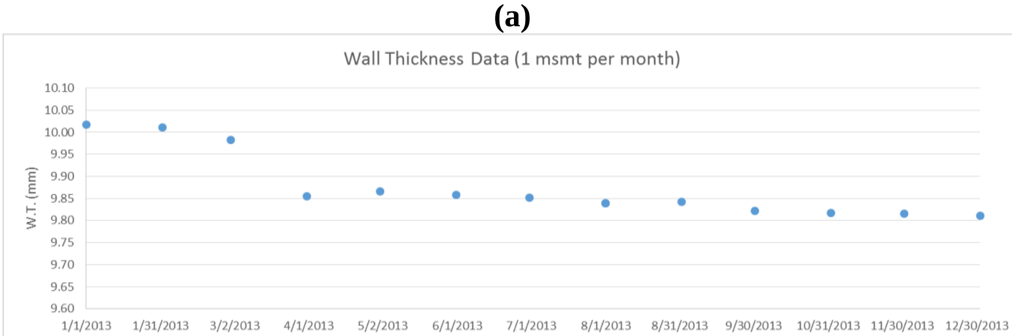
When considering a measurement of once per year as might be had from manual UT measurements, only a coarse corrosion-rate calculation is available. Over several years, an operator might get a general feeling for the long-term corrosion rate, but statistically it is impossible to place any certainty on this measurement so the ability to use the corrosion rate as a predictive tool (for scheduling maintenance for instance) is poor.

Moving to a relatively infrequent measurement cycle of 1X per month allows a much better picture of the process of wall-thickness reduction. Separate corrosion rates are evident in the data, including evidence of an episodic event of very high wall-thickness reduction. While a large improvement over a once-per-year measurement cycle, the relatively small amount of data still limits the ability to calculate corrosion rates accurately. Thus, the ability to distinguish two different corrosion rates is impaired and limits the efficacy of using the measurement as a process-control tool.

More frequent measurements, for instance once-per-week, once-per-day or even more often, allow statistical tools to be used to characterize and remove measurement noise, achieving corrosion-rate measurement precision in the range of 1 MPY. As such, installed ultrasonic thickness measurements become a tool for monitoring process conditions as they impact the corrosion/erosion rate within a piping circuit, vessel, heat exchanger shell, or other asset. Numerical tools such as data filtering and linear regression are easily deployed in software.



(a)



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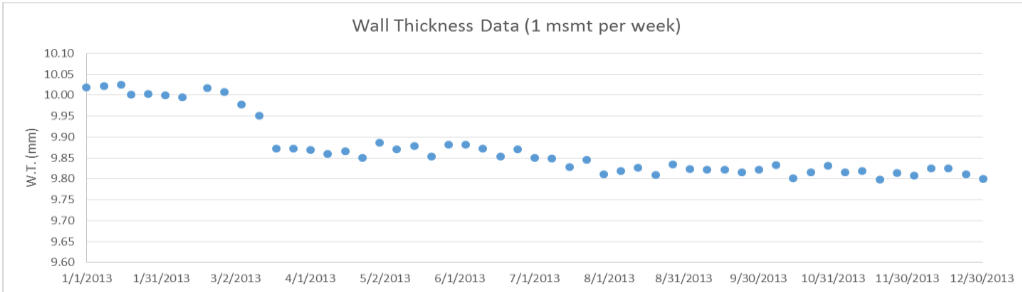
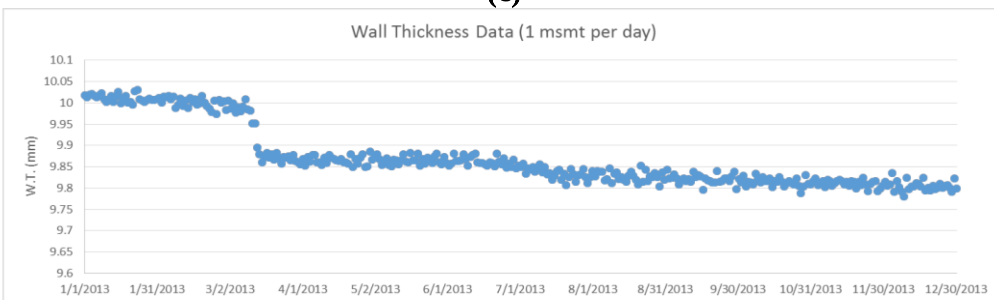


(c)



(d)

Figure 6: Wall thickness monitoring data with collection intervals of: (a) 1x/year, (b) 1x/month, (c) 1x/week and (d) 1x/day.

5.1 Precision of Corrosion-Rate Measurements

With certain assumptions, the uncertainty of the slope and intercept coefficients can also be calculated. As an example, a calculation for a measurement system with 1 mil standard deviation and measurement intervals from 4X per day to 1X per week the result makes it clear that the accuracy of corrosion rates calculated from linear regression can be improved by making more frequent measurements over a longer time interval, even for a measurement system with modest precision (1 mil (0.001” or 0.025 mm) standard deviation).

While even infrequent measurements such as 1X per week can result in accurate corrosion rate calculations, it is necessary to perform the calculation over a much longer time frame. This is undesirable from a process-feedback perspective and also opens the possibility that the corrosion rate is not uniform over the time period and thus invalidates the use of linear regression to accurately calculate corrosion rate.

The following data set shows a corrosion measurement resolution of 0.001” (0.025 mm) / month along with acoustic-velocity temperature correlation. Resolution of 0.0001” or 2.5 microns is achievable. The digitized RF waveforms used to make the thickness calculations are saved for each measurement.

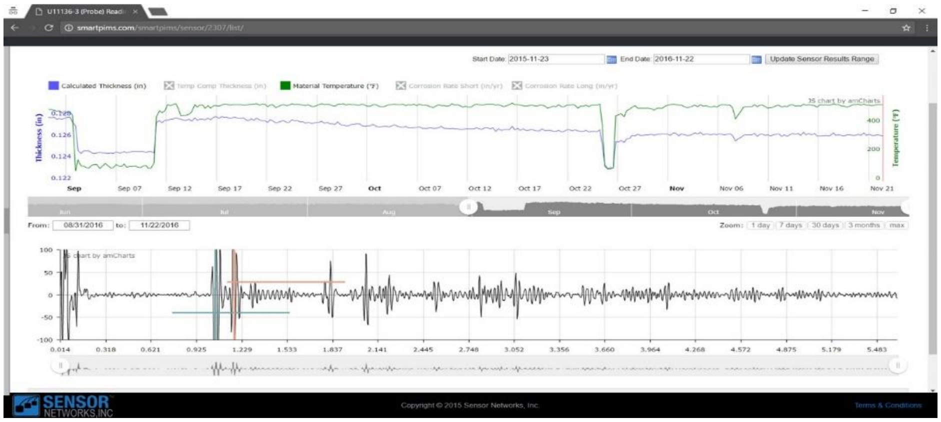


Figure 7: Ultrasonic thickness measurement resolution

6.0 Applications of Installed UT Sensors:

The potential applications of installed UT sensors are virtually unlimited, any asset or TML currently being monitored for corrosion/erosion is a candidate.

Converting a point from conventional monitoring can involve many factors including:

- The criticality of the asset or TML and potential loss of assets, loss of life, lost production, environmental damage / fines, damage to company image; the cost of cost of access – scaffolding cost, lagging /delagging, offshore access, personnel costs.
- The desire for improved corrosion management including trending, verification of corrosion mitigation strategies (<5 MPY), feedback for chemical inhibitors, planned maintenance, etc.
- The need for high-integrity data to enhance RBI and mechanical integrity programs.
- A desire to eliminate the human factor present in manual UT.
- A desire to remove inspection personnel from hazardous areas.
- Regulatory and Code compliance.

Locations currently monitored using ER probes: Figure 5 shows traditional points in a refinery's crude unit where process corrosion rate is measured using electrical-resistance probes. While this technology is currently status quo, it suffers from several shortcomings including measurement noise due to temperature changes, susceptibility to conductive deposit causing "negative" corrosion readings and relatively short life. ER probes only give a proxy to asset health as the actual asset is not being measured.

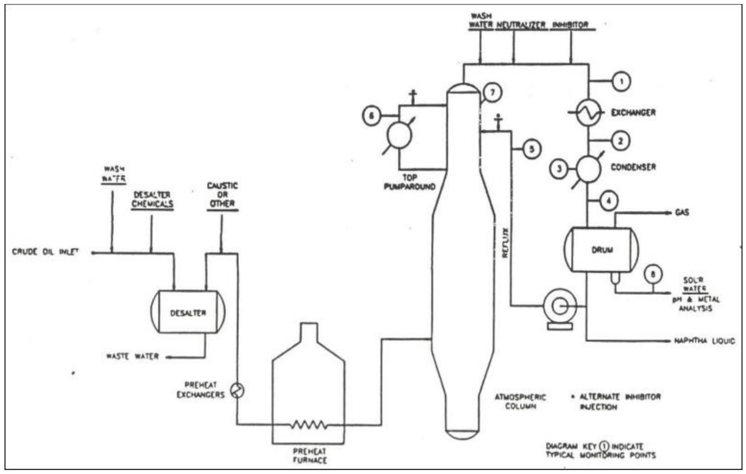


Figure 8: Schematic view of refining crude unit showing corrosion monitoring locations.

Injection / Mix-point Corrosion: Injection/Mix-point corrosion has been responsible for many serious refinery incidents and is episodic in nature, only happening for certain process conditions or during process upsets. API 570 specifies inspection guidelines and NACE IP 34101 provides specific process guidelines to minimize injection point damage. While manual UT and RT provide static monitoring of potential damage areas their use may not coincide with the timeframe where episodic damage occurs and therefore will require repeat inspections of potential damage areas. Installed UT sensors can provide dynamic monitoring of suspected injection point damage locations without repeated access mobilizations.

Figure 9: Pipe failures due to Injection/Mix-point corrosion.

Crude Overhead: Crude Unit Overhead with Chemical Injection and/or Water Washes is subject to periodic inspections per API 570. Many overhead lines have no platform access making these inspections difficult and costly. UT and RT can provide useful inspection data, but it is costly to obtain if crane access / scaffolding is required. Installed UT sensors can be installed and accessed on a continuous basis to reduce cost of access and to improve plant operational knowledge.

Figure 10: Crude unit overhead line corrosion monitoring at 300-degrees F using dual-element transducers and cellular back-haul.

Buried Pipelines: Smart-pigging is the often-used solution for monitoring pipelines, and most large-diameter, long-distance transmission lines are fitted with the proper valves, pig launchers, to allow inspection with smart pigs. Most secondary lines however are too small in diameter and not appropriately configured to allow pigging, thus requiring excavation and visual inspection. Federal regulations such as 49 CFR require repeated excavation of problem areas. Installed UT sensors can be buried in problem areas and then can be periodically measured without further excavation costs.

Riser Monitoring: Sand Erosion can occur at change-in-direction or diameter in offshore production risers due to solids production. This erosion is typified by a smooth surface with a sand dune pattern. Riser locations where sand erosion may occur can be difficult to access and inspect with conventional UT or RT in addition to the high mobilization costs of personnel to offshore facilities. Helicopter access to an offshore facility can cost in the range of $50,000 USD per trip. While acoustic technologies can be used to detect the impingement of sand particles on the internal bore of the riser, these techniques only determine the presence or absence of sand and do not measure the remaining wall thickness of the asset. UT installed sensors can be applied to suspect areas for accurate monitoring without the need for manual access and can be integrated with platform or FPSO control systems for a “control panel” view of asset health.

CONCLUSIONS

Corrosion/Erosion is a widespread and costly problem for US and Global infrastructure causing degradation of assets due to reduced wall thickness and the corresponding reduction in load-bearing capacity with potential for adverse and catastrophic consequences. Currently, manual ultrasonics and radiography are widely deployed to measure asset integrity for wall-thickness degradation, such as in high-energy piping circuits and pressure vessels in the O&G and Power Generation industries. While these techniques are common and accepted, there are drawbacks in the accuracy and precision of these measurements and they only take a periodic snapshot view of asset health. Asset managers desire a more real-time view of the health of their facilities and equipment similar to the KPI view that they get when monitoring process variables. Additionally, the difficulty and cost of access, safety concerns and regulatory pressures are further driving interest in installed monitoring systems.

Installed and network-distributed ultrasonic sensors have the potential for improved asset-health monitoring compared to current manual inspection techniques. Ultrasonic sensors are non-intrusive and are permanently installed with automated or semi-automated data-collection schemes. Ultrasonic sensors reduce key variables, such as operator interaction, resulting in improved measurement accuracy and precision. Other key noise variables such as temperature change can be removed automatically with temperature sensors and software. Installed ultrasonic monitoring systems can provide more and better data, allowing the use of statistical tools such as linear regression to provide corrosion-rate measurements on par with other technologies such as ER probes and further allowing enhanced trending and feedback to process variables.

Opportunities for corrosion/erosion monitoring systems are widespread, including applications such as ER probe or coupon replacement, mix-point corrosion, crude overhead lines, effluent air coolers, buried pipelines and offshore risers as well as an almost unlimited variety of applications where conventional UT and RT inspections are deployed. The need exists for a flexible solution to meet the application and customer requirements including wired and wireless solutions.

The authors have developed a flexible solution for corrosion/erosion monitoring which uses a novel, patent-pending approach: Network-distributed ultrasonic sensors along a multi-drop system using industry standard, Modbus over RS-485 wired approach, or alternatively a cellular network. This solution allows the deployment of hundreds to thousands of measurement points in a cost-effective manner. High accuracy and precision is obtained using features such as temperature compensation and linear regression that are built into the cloud-based software platform which offers unparalleled access to asset-health data.

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